Appendix 3-1. NO_x Rate Development in EPA Base Case 2004, v.2.1.9

In EPA Base Case 2004 and the policy model runs built upon this base case (as in previous EPA base cases) NO_x combustion controls are not represented as retrofit options that the model chooses. Instead, in setting up each model run, the presence or absence of combustion controls is captured in the NO_x rates assigned to existing units. State-of-the-art NO_x combustion controls are assumed to be used in geographical areas that are subject to NO_x control limits that go into effect after 2003. Within the NO_x SIP Call region, however, no additional combustion controls were assumed, so the controlled base and controlled policy NO_x rates are the same.

Each existing fossil-fuel-fired generating unit in the NEEDS, v.2.1.9 database has four NO_x emission rates associated with it from which the IPM set-up program assigns the rate applicable for each specific model scenario. A “Base Rate” for NO_x is said to apply, if under a particular modeled scenario, a unit is not located in a geographical area affected by NO_x control limits beyond those already reflected in the baseline emission rate data incorporated into NEEDS from the sources described in Steps 2-5 below. A “Policy Rate” for NO_x applies if a unit is located in a geographical area affected by NO_x control limits beyond those reflected in the baseline emission rate data. This results in four NO_x rates being associated with each generating unit:

Mode 1= Uncontrolled Base Rate
Mode 2= Controlled Base Rate
Mode 3= Uncontrolled Policy Rate
Mode 4 = Controlled Policy Rate

There are several things to note about the Modes 1-4 designations. “Controlled” refers to the rates provided by post combustion NO_x controls, i.e., selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR), if they are present at the unit. For generating units that do not have post-combustion controls, the controlled rate will be the same as the uncontrolled rate. For generating units that do have post-combustion controls, the controlled and uncontrolled rates will differ unless the post-combustion controls are operated year round. In such cases, the “uncontrolled rates” are assigned the “controlled” NO_x emission rate. Base and Policy NO_x rates will be same if the unit has state-of-the-art NO_x combustion controls or is in the SIP Call region where current combustion controls are assumed to be retained. Base and policy rates will differ if a unit does not currently have state-of-the-art combustion controls that would be installed in response to a NO_x policy. Examples of each of these instances are shown in Table A 3-1:1.

The list below enumerates the procedure that is used to derive the four emission rates. Several aspects of the list are worth noting. (1) Winter NO_x rates reported in EPA’s Emission Tracking System were used as proxies for the uncontrolled base NO_x rates. (2) There were several units covered by New Source Review (NSR) settlements that were required to run their SCR year round. This was implemented by making their Mode 1, Mode 2, Mode 3 and Mode 4 NO_x rates all equal to the rate resulting from annual application of SCR. (3) If a unit does not report having combustion controls, but has an emission rate below a specific cut-off rate (shown in Table 3-1:2), it is considered to have combustion controls. (4) For units with combustion controls that were not state-of-the-art, emission rates without those combustion controls were back calculated and then policy rates were derived assuming the reductions provided by state-of-the art combustion controls. (5) The NO_x rates achievable by state-of-the-art combustion controls vary by coal rank (bituminous and sub-bituminous) and boiler type. The equations used to derive these rates are shown in Table 3-1:3.

Process Used to Derive Base and Policy NO_x Rates in EPA Base Case 2004

Step 1: Four modes for NO_x rates were defined:

Mode 1= Uncontrolled Base Rate
Mode 2= Controlled Base Rate
Mode 3= Uncontrolled Policy Rate
Mode 4 = Controlled Policy Rate

Step 2: NO_x rates were derived for the summer and winter seasons from the data reported to EPA under Title IV of the Clean Air Act Amendments of 1990 (Acid Rain Program) and NO_x budget program. This data is maintained in EPA's Emission Tracking System (ETS) and, consequently, the resulting values are called ETS emission rates.

Step 3: ETS winter NO_x rates were used as proxies for uncontrolled baseline NO_x rates (Mode 1).

Step 4: For non-coal units in NEEDS without ETS NO_x rates, defaults were developed from similar units with ETS rates. This was done by state, plant type, and post combustion control. If state level defaults were not available for certain generating units then national level defaults by plant type and post combustion control were used.

Step 5: For coal units without ETS NO_x rates, defaults were developed from similar units with ETS rates. This was done by state, firing, bottom, combustion control, and post combustion control. If state level defaults were not available for certain boilers then national level defaults by firing, bottom, combustion control, and post combustion control were used.

Step 6: Mode 2 was calculated by applying a 90% reduction to the Mode 1 rate of coal units with an SCR as long as this result was higher than the floor rate of .06 lb/mmBtu. For units with SNCR the Mode 2 rate was derived by applying a 35% reduction to the Mode 1 rate. No floor rate was used.

Step 7: There were several units covered by New Source Review (NSR) settlements that were required to run their SCR year round. This was implemented by making their Mode 1, Mode 2, Mode 3 and Mode 4 NO_x rates all equal to the rate resulting from annual application of SCR.

Step 8: For boilers that were not listed as having either combustion or post-combustion controls, an additional engineering check was performed to determine if they should be considered to have combustion controls. Their Mode 1 NO_x rate was compared with the cut-off NO_x rate indicative of the presence of combustion controls in similar boilers. If the units Mode 1 NO_x rate was less than or equal to the cut-off rate (in columns 2-4 of Table 3-1:2), then the boiler was assumed to have a NO_x combustion control and the Mode 3 rate was assigned the same value as the Mode 1 rate.

Step 9: The technology configuration for units listed as having combustion controls were checked to see if they reflected the presence of state of the art NO_x controls. If not, calculations were performed to provide a NO_x rate that would result with state of the art combustion controls. The calculations (described in Step 10) were tailored to the specific configuration of controls that were in place. This rate was used as the Mode 3 Uncontrolled Policy NO_x Rate. This step was not applied to units in the SIP Call region* since they already had their combustion controls in operation and were unlikely to move to a higher level of control. The step was also not applied to units that had SCR and to units whose Mode 1 rate was lower than the cut-off rate (as described in Step 8). All such boilers that were excluded from this step, were assigned identical Mode 1 and Mode 3 NO_x rates.

Step 10: For wall- and tangentially fired units the following procedure was used to calculate the state-of-the-art combustion control NO_x rates required in Step 9. Based on the specific controls in place, one of several candidate equations (column 4 in Table 3-1:3) was first used to back-calculate the uncontrolled emission rate that would have resulted without the existing controls. (In cases where the applicable equation could not be solved a default removal rate (column 5 in Table 3-1:3) was used to back-calculate the uncontrolled emission rate.) Once the uncontrolled NO_x rate was calculated, a removal efficiency equation for the applicable state of the art NO_x combustion control was applied to derive the Mode 3 policy rate. The specific removal equation used depended on the type of boiler and the predominant coal rank (bituminous or subbituminous) consumed by the unit. (It is one of those shown in bold italic in column 4 of Table 3-1:3)

Step 11: The rate derived in Step 10 was compared to the applicable NO_x rate floor (columns 5-7 of Table 3-1:2) that engineering analysis indicated applied to each burner type. If the rate derived in Step 10 was below the applicable floor rate, the floor rate, not the Step 10 rate, was used as the Mode 3 rate.

Step 12: The removal rates for combustion controls on cell, cyclone, and vertically fired boilers were assumed to be 60%, 50%, and 40% respectively. These were the same assumptions used in EPA Base Case 2003. (See Table A.5..2.2 in *Documentation Supplement for EPA Modeling Applications (V.2.1.6) Using the Integrated Planning Model* (EPA 430/R-03-007), July 2003.)

Step 13: The Mode 4 emission rate was calculated by applying a 90% reduction to the Mode 3 rate of coal units with an SCR as long as this result was higher than the floor rate of .06 lb/mmBtu. For units with SNCR the Mode 4 rate was derived by applying a 35% reduction to the Mode 3 rate. No floor rate was used. (This is the same procedure used to derive the Mode 2 rate from the Mode 1 rate in Step 6.)

*The SIP Call region includes Alabama, Connecticut, Delaware, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, District of Columbia, Georgia, and Missouri.

Table 3-1:1. Examples of Base and Policy NO_x Rates Occurring in EPA Base Case 2004.							
Plant Name	UniqueID	Post-CombControl	Uncontrolled NO_x Base Rate	Controlled NO_x Base Rate	Uncontrolled NO_x Policy Rate	Controlled NO_x Policy Rate	Explanation
Situation 1: For generating units that do not have post-combustion controls, the controlled and uncontrolled rates will be the same.							
JACK WATSON	2049_B_5	None	0.55	0.55	0.41	0.41	Situation 4 also applies, i.e., unit had LNB and now added OFA so see drop in policy rates.
Situation 2a: For generating units that do have post-combustion controls, the controlled and uncontrolled rates will differ							
BIG SANDY	1353_B_BSU2	SCR	0.48	0.06	0.48	0.06	(1) Has SCR so see difference between uncontrolled and controlled rates (2) Situation 3b also applies.
Situation 2b: . . . unless the post-combustion controls are operated year round. In such cases, the "uncontrolled rates" are assigned the "controlled" NO_x rate.							
ECAO_KY _Coal Steam	013_C_013	SCR	0.06	0.06	0.06	0.06	Planned/Committed unit so run SCR year-round
Situation 3a: Base and Policy NO_x rates will be same if the unit has state-of-the-art NO_x combustion controls or . . .							
SOUTH OAK CREEK	4041_B_5	None	0.18	0.18	0.18	0.18	Situation1 also applies.
W A PARISH	3470_B_WAP5	SCR	0.14	0.06	0.14	0.06	Situation 2a also applies.
Situation 3b: . . . is in the SIP Call region where current combustion controls are assumed to be retained.							
WIDOWS CREEK	50_B_7	SCR	0.42	0.06	0.42	0.06	Situation 2a also applies.
SIBLEY	2094_B_3	None	0.68	0.68	0.68	0.68	(1) Has NO_x combustion control and is in SIP so doesn't get added combustion control. High NO_x rate because it is a cyclone unit (2) Situation 1 also applies.
Situation 4: Base and policy rates will differ if a unit does not currently have state-of-the-art combustion controls and would install such controls in response to a NO_x policy.							
SCHILLER	2367_B_4	SNCR	0.37	0.24	0.32	0.21	(1) Drop in uncontrolled policy NO_x rate compared to uncontrolled base rate is due to addition of combustion controls. (Note 0.32 is floor.) (2) Unit has SNCR so Situation #2a also applies and you see a 35% drop between uncontrolled and controlled NO_x rates.

Table A3-1:2. Cutoff and Floor NO_x Rates (lb/mmBtu)

Boiler Type	Cutoff Rate (lbs. per MMBtu) Bit	Sub	Lig	Floor rate (lbs. per MMBtu) Bit	Sub	Lig
Wall-Fired Dry-Bottom	0.43	0.33	0.29	0.32	0.18	0.18
Tangentially-Fired	0.34	0.24	0.22	0.24	0.12	0.17
Cell-Burners	0.43	0.43	0.43	0.32	0.32	0.32
Cyclones	0.62	0.67	0.67	0.47	0.49	0.49
Vertically-Fired	0.57	0.44	0.44	0.49	0.25	0.25

Bit = bituminous, Sub = subbituminous, Lig = lignite

Table A 3-1:3. NO_x Removal Efficiencies for Different Combustion Control Configurations. (State of the art configurations are shown in bold italic.)

Boiler Type	Coal Type	Combustion Control Technology	Fraction of Removal	Default Removal
Dry Bottom Wall-Fired	Bituminous	LNB	0.163 + 0.272* Base NO_x	0.568
		LNB + OFA	***0.313 + 0.272* Base*** NO_x	***0.718***
Dry Bottom Wall-Fired	Sub-bituminous/Lignite	LNB	0.135 + 0.541* Base NO_x	0.574
		LNB + OFA	***0.285 + 0.541* Base*** NO_x	***0.724***
Tangentially-Fired	Bituminous	LNC1	0.162 + 0.336* Base NO_x	0.42
		LNC2	0.212 + 0.336* Base NO_x	0.47
		LNC3	***0.362 + 0.336* Base*** NO_x	***0.62***
Tangentially-Fired	Sub-bituminous/Lignite	LNC1	0.20 + 0.717* Base NO_x	0.563
		LNC2	0.25 + 0.717* Base NO_x	0.613
		LNC3	***0.35 + 0.717* Base*** NO_x	***0.713***

LNB = low NO_x burner. OFA = overfire air. LNC = low NO_x control

Appendix 3-2. State Multipollutant Regulations Incorporated in EPA Base Case 2004, v.2.1.9.

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Status
Arizona, New Mexico, Oregon, Utah, Wyoming	WRAP	SO_2	Cap of 198,900 tons on all fossil > 25 MW	2018	Added in v.2.1.9
Connecticut	Executive Order 22	NO_x	Emission rate of 0.15 lb/mmBtu for fossil units > 15 MW	2007	Retained from v.2.1
	Executive Order 19	SO_2	Emission rate of 0.33 lb/mmBtu for fossil units > 15 MW	2007	Retained from v.2.1
	Public Act No. 30-72	Hg	Emission rate of 0.0000006 lb/mmBtu for all coal-fired plants, alternatively can meet a 90% emission reduction	2008	Added in v.2.1.9
Illinois	Title 35, Section 217.706	NO_x	Emission rate of 0.25 lb/mmBtu for fossil units > 25 MW. Some units are allowed to average their emissions; others must meet the rate on a facility basis.	2007	Added in v.2.1.9
Maine	Chapter 145 NO_x Control Program	NO_x	Emission rate of 0.22 lb/mmBtu for fossil units > 25 MW built before 1995 with a heat input capacity between 250 and 750 mmBtu/hr	2007	Added in v.2.1.9
		NO_x	Emission rate of 0.15 lb/mmBtu for fossil units >25MW built before 1995 with a heat input capacity greater than 750 MmBtu/hr	2007	Added in v.2.1.9
Massachusetts	310 CMR 7.29	NO_x	Emission rate of 1.5 lb/MWh for the 6 grandfathered units in state	2007	Retained from v.2.1.6
		SO_2	Emission rate of 3.0 lb/MWh for the 6 grandfathered units in state	2007	Retained from v.2.1.6
		Hg	Included in bill but limits not yet decided	-	-
		CO2	Emission rate of 1,800 lb/MWh for the 6 grandfathered units in state	2007	Retained from v.2.1.6
Minnesota	Agreement between Minnesota Pollution Control Agency and Xcel Energy	NO_x, SO_2, Hg	Specific Xcel Energy plants must repower or install controls	2007-2009	Added in v. 2.1.9
Missouri	Title 10, Div 10, Ch 6.350	NO_x	Summer season cap of 43,950 tons on all units > 25 MW	2007	Retained from v.2.1
New Hampshire	ENV-A2900	NO_x	Cap of 3,644 tons on all existing fossil steam units	2007	Retained from v.2.1.6
		SO_2	Cap of 7,289 tons on all existing fossil steam units	2007	Retained from v.2.1.6
		Hg	No HG state emission cap on existing fossil steam units	—	—

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Status
		CO2	Cap of 5,425,866 tons on all existing fossil steam units	2007	Retained from v.2.1.6
	ENV-A3200	NO_x	Emission rate of 0.15 lb/mmBtu for fossil plants > 15 MW in Hillsborough, Merrimack, Rockingham, and Stafford counties	2007	Added in v. 2.1.9
		NO_x	Emission rate of 0.15 lb/mmBtu for fossil plants > 15 MW in all other counties	2007	Added in v. 2.1.9
New York	Part 237	NO_x	Non-ozone season cap of 39,908 tons on fossil units > 25 MW	2007	Added in v. 2.1.9
		SO_2	Annual cap of 197,046 tons starting in 2007 and 131,364 tons starting in 2008 on fossil units > 25 MW	2007	Added in v. 2.1.9
North Carolina	Clean Smokestacks Act	NO_x	Cap of 25,000 tons on coal-fired units belonging to CP&L >25MW	2007	Retained from v.2.1.6
		NO_x	Cap of 35,000 tons starting in 2007 and 31,000 starting in 2009 on coal-fired units belonging to Duke Energy >25MW	2007	Retained from v.2.1.6
		SO_2	Cap of 100,000 tons on 14 coal-fired units belonging to CP&L >25MW by 2009 and 50,000 tons by 2013 [Title IV allowances allocated to North Carolina units that exceed the State's cap will be retired from the federal program in IPM]	2009	Retained from v.2.1.6
		SO_2	Cap of 150,000 tons on 14 coal-fired units belonging to Duke Energy >25MW by 2009 and 80,000 tons by 2013 [Title IV allowances allocated to North Carolina units that exceed the State's cap will be retired from the federal program in IPM]	2009	Retained from v.2.1.6
Oregon	Oregon Administrative Rules, Chapter 345, Division 24	CO2	Annual emission rate of 675 lb/MWh for new Combustion turbines burning natural gas with a CF >75%, and all new non-base load plants (with a CE <=75%) emitting CO2	2007	Added in v.2.1.9
Texas	Senate Bill 7	NO_x - East	Annual emission cap of 58,365 tons for all grandfathered fossil > 25MW [all of Texas traversed by or east of Rt 35]	2007	Retained from v.2.1.6
		NO_x - West	Annual emission cap of 18,028 tons for all grandfathered fossil > 25MW [all of Texas not in East region or El Paso county]	2007	Retained from v.2.1.6
		NO_x - El Paso	Annual emission cap of 1,058 tons for All grandfathered fossil > 25MW [El Paso county]	2007	Retained from v.2.1.6

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Status
		SO_2 - East	Annual emission cap of 111,183 tons for all grandfathered fossil > 25MW [all of Texas traversed by or east of Rt 35]	2007	Retained from v.2.1.6
		SO_2 - West	25% reduction from 1997 baseline for all grandfathered fossil > 25MW [all of Texas not in East region or El Paso county]	-	-
		SO_2 - El Paso	25% reduction from 1997 baseline for all grandfathered fossil > 25MW [El Paso county]	-	-
	Ch. 117	NO_x - Houston	Cap of 8,459 tons applied to all fossil units	2007	Retained from v.2.1
		NO_x - Dallas/Fort Worth	unit-specific rate limits that can alternatively be met by a system-wide averaging cap of 2,164 tons applied to all fossil units	2007	Retained from v.2.1
		NO_x - East/Central	unit-specific rate limits that can alternatively be met by a system-wide averaging cap of 123,528 tons applied to all fossil units	2007	Retained from v.2.1
Wisconsin We Energies (WEPCO) *owns 5 coal and 3 natural gas facilities affected by agreement*	Cooperative agreement between WEPCO and DNR Wisconsin Dept of Natural Resources (PUB-AM-316 2001)	SO_2	System-wide emission limit of .70 lb/mmBtu in 2008 and .45 lb/mmBtu in 2013 for WEPCO coal plants	2007/2012	Retained from v.2.1.6
		NO_x	System-wide emission limit of .25 lb/mmBtu in 2008 and .15 lb/mmBtu in 2013 for WEPCO coal plants	2007/2012	Retained from v.2.1.6
		Hg	Planned 10% reduction from ‘98-‘00 levels by 2007 and 50% Reduction by 2012, but no cap approved yet	-	-

Appendix 3-3. New Source Review (NSR) Settlements in EPA Base Case 2004, v.2.1.9.

Company and Plant	Unit	Settlement Actions											Notes
		Retire/Repower		SO_2 Control			NO_x Control			PM or Mercury Control			
		Action	Effective Date	Equipment	Percent Removal or Rate (lb/mmBtu)	Effective Date	Equipment	Rate (lb/mmBtu)	Effective Date	Equipment	Rate (lb/mmBtu)	Effective Date	
SIGECO													
F B Culley	Unit 1	Repower to natural gas (or retire)	31-Dec-06										Settlement requires that unit 1 must either shutdown or repower to natural gas. In EPA Base Case 2004 EPA assumed that the unit will be repowered.
	Unit 2			Improve & Continuously Operate Existing FGD (shared by units 2 & 3)	95%	30-Jun-04							Improved operation of the FGD is hardwired into EPA Base Case 2004.
	Unit 3			Improve & Continuously Operate Existing FGD (shared by units 2 & 3)	95%	30-Jun-04	Operate Existing SCR Continuously	0.1	1-Sep-03	Install & Continuously Operate a Baghouse	0.015	30-Jun-07	Improved operation of the FGD, continuous operation of the SCR, and installation of the baghouse are hardwired into EPA Base Case 2004.
PSEG FOSSIL													
Bergen	Unit 2	Repower to combined cycle	31-Dec-02										This action is hardwired into EPA Base Case 2004.
Hudson	Unit 2			Install Dry FGD (or approved alt tech) & Operate at All Times Unit Operates	0.15	31-Dec-06	Install SCR (or approved alt tech) & Operate Year-Round	0.1	1-May-07	Install Baghouse (or approved alt tech)	0.015	31-Dec-06	The FGD and baghouse are hardwired into EPA Base Case 2004. The SCR is modeled as an individual emissions constraint. The settlement requires coal with monthly avg sulfur content no greater than 2% at units operating FGD -- this limit is modeled as a coal choice exception in EPA Base Case 2004.
Mercer	Unit 1			Install Dry FGD (or approved alt tech) & Operate at All Times Unit Operates	0.15	31-Dec-10	Install SCR (or approved alt tech) & Operate Year-Round	0.13	Ozone season only - 2005; annually May 1, 2006				The SCR is hardwired into EPA Base Case 2004; the FGD is modeled as an individual emissions constraint. The settlement requires coal with monthly avg sulfur content no greater than 2% at units operating FGD -- this limit is modeled as a coal choice exception in EPA Base Case 2004.
	Unit 2			Install Dry FGD	0.15	31-Dec-	Install SCR	0.13	Ozone season only - 2004;				The SCR is hardwired into EPA

Company and Plant	Unit	Settlement Actions											Notes
		Retire/Repower		SO_2 Control			NO_x Control			PM or Mercury Control			
		Action	Effective Date	Equipment	Percent Removal or Rate (lb/mmBtu)	Effective Date	Equipment	Rate (lb/mmBtu)	Effective Date	Equipment	Rate (lb/mmBtu)	Effective Date	
				(or approved alt tech) & Operate at All Times Unit Operates		12	(or approved alt tech) & Operate Year-Round		annually May 1, 2006				Base Case 2004; the FGD is modeled as an emission constraint. The settlement requires coal with monthly avg sulfur content no greater than 2% at units operating FGD -- this limit is modeled as a coal choice exception in EPA Base Case 2004.
TECO													
Big Bend	Unit 1			Existing Scrubber (shared by units 1 & 2)	95% (95% or 0.25)	Sept 1, 2000 (Jan 1, 2013)	Install SCR (or other approved tech)	0.1	1-May-09				Settlement requires that units 1, 2, 3 and 4 elect to either shutdown, repower, or remain coal-fired (and install SCR), and advise EPA of decision by May 1, 2007 for units 1 through 3 and by May 1, 2005 for unit 4. The FGD are already in place thus are built into EPA Base Case 2004. The SCR requirements are modeled as individual emissions constraints. SCR effective dates in the settlement for units 1 through 3 are: (1) for the first unit to remain coal fired or if only one is to be coal-fired, May 1, 2008; (2) for the second unit to remain coal-fired, if there is one, May 1, 2009; (3) for the third unit, if there is one, May 1, 2010. For simplification EPA assumed an effective date in 2009 for all three units.
	Unit 2			Existing Scrubber (shared by units 1 & 2)	95% (95% or 0.25)	Sept 1, 2000 (Jan 1, 2013)	Install SCR (or other approved tech)	0.1	1-May-09				
	Unit 3			Existing Scrubber (shared by units 3 & 4)	93% if units 3 & 4 are operating ; 95% or an emission rate of 0.3 if unit 3 alone is operating (95% or 0.25)	2000 (Jan 1, 2010)	Install SCR (or other approved tech)	0.1	1-May-09				
	Unit 4			Existing Scrubber (shared by units 3 & 4)	93% if units 3 & 4 are operating	year 2000	Install SCR (or other approved tech)	0.1	1-Jun-07				
Gannon	Six Units	Retire all six coal units and repower	31-Dec-04										Settlement requires all six coal units to shutdown by Dec 31,

		Settlement Actions											
		Retire/Repower		SO_2 Control			NO_x Control			PM or Mercury Control			
Company and Plant	**Unit**	**Action**	**Effective Date**	**Equipment**	**Percent Removal or Rate (lb/mmBtu)**	**Effective Date**	**Equipment**	**Rate (lb/mmBtu)**	**Effective Date**	**Equipment**	**Rate (lb/mmBtu)**	**Effective Date**	**Notes**
		at least 550 MW of coal capacity to natural gas											2004. By May 1, 2003 at least 200 MW of coal capacity must be repowered and by Dec 31, 2004 additional coal capacity must be repowered such that total coal capacity repowered is at least 550 MW. Retirement of all coal units and repowering as two natural gas units are built into EPA Base Case 2004. New plant is called Bayside Station.
We Energies (WEPCO)													
Presque Isle	Units 1, 2, 3 and 4	Retire or install SO_2 and NO_x controls	31-Dec-12	Install FGD (or approved equiv control tech) & Operate Continuously	95% or 0.1	31-Dec-12	Install SCR (or approved equiv control tech) & Operate Continuously	0.1	31-Dec-12				WEPCO may elect to retire or install controls at Presque Isle units 1 through 4. For EPA Base Case 2004, we imposed the SO_2 and NO_x limits as individual emission constraints.
	Units 5 & 6						Install & Operate Low NO_x Burner		31-Dec-03				LNBs on Presque Isle units 5 & 6 are hardwired in EPA Base Case 2004.
	Units 7 & 8						Operate Existing Low NO_x Burner		31-Dec-05	Install Baghouse			LNBs on units Presque Isle 7, 8 & 9 are hardwired in EPA Base Case 2004. The settlement requires demonstration of full-scale TOXECON with activated carbon injection for mercury removal at units 7, 8 & 9. Baghouses are being installed for the TOXECON, and these units already have ESP in place. In EPA Base Case 2004, ESP and baghouses are hardwired on these units, and mercury emissions modification factor (EMF) for ESP & baghouse combination is applied. Future versions of IPM may include a greater mercury removal efficiency at these units, depending on the outcome of the TOXECON demonstration.
	Unit 9						Operate Existing Low NO_x Burner		31-Dec-06	Install Baghouse			

Company and Plant	Unit	Settlement Actions											Notes
		Retire/Repower		SO_2 Control			NO_x Control			PM or Mercury Control			
		Action	Effective Date	Equipment	Percent Removal or Rate (lb/mmBtu)	Effective Date	Equipment	Rate (lb/mmBtu)	Effective Date	Equipment	Rate (lb/mmBtu)	Effective Date	
Pleasant Prairie	Unit 1			Install FGD (or approved equiv control tech) & Operate Continuously	95% or 0.1	31-Dec-06	Install SCR (or approved equiv control tech) & Operate Continuously	0.1	31-Dec-06				(Settlement requires compliance with the specified SO_2 & NO_x efficiency or limit by one-month after the required installation date shown in this table for Pleasant Prairie units 1 & 2.) In EPA Base Case 2004, FGD on unit 1 and SCR on units 1 & 2 are hardwired. FGD on unit 2 is modeled as an individual emissions constraint.
	Unit 2			Install FGD (or approved equiv control tech) & Operate Continuously	95% or 0.1	31-Dec-07	Install SCR (or approved equiv control tech) & Operate Continuously	0.1	31-Dec-03				
Oak Creek	Units 5 & 6	Retire or install SO_2 and NO_x controls	31-Dec-12	Install FGD (or approved equiv control tech) & Operate Continuously	95% or 0.1	31-Dec-12	Install SCR (or approved equiv control tech) & Operate Continuously	0.1	31-Dec-12				WEPCO may elect to retire or install controls at Oak Creek units 5 & 6. For EPA Base Case 2004, we imposed the SO_2 and NO_x limits as individual emission constraints.
	Unit 7			Install FGD (or approved equiv control tech) & Operate Continuously	95% or 0.1	31-Dec-12	Install SCR (or approved equiv control tech) & Operate Continuously	0.1	31-Dec-12				(Settlement requires compliance with the specified SO_2 & NO_x efficiency or limit by one-month after the required installation date shown in this table for Oak Creek units 7 & 8.) In EPA Base Case 2004, the required SO_2 & NO_x controls on these units are modeled as individual emission constraints.
	Unit 8			Install FGD (or approved equiv control tech) & Operate Continuously	95% or 0.1	31-Dec-12	Install SCR (or approved equiv control tech) & Operate Continuously	0.1	31-Dec-12				
Port Washington	Units 1, 2, 3 and 4	Retire (also have option to install SO_2 and NO_x controls but have opted to retire & repower -- see notes column)	Units 1, 2 & 3 by Dec 31, '04; unit 4 by entry of the consent decree										WEPCO announced plans to retire Port Washington and repower with two natural gas units. Retirement of the four coal units and repowering of the first natural gas unit are hardwired in EPA Base Case 2004.
Valley	Boilers 1, 2, 3 & 4						Operate Existing Low NO_x Burner		30-days after date of lodging of the Consent Decree				LNBs on units 1, 2, 3 & 4 are hardwired in EPA Base Case 2004.
VEPCO													
Mount Storm	Units 1, 2 and 3			FGD (Construct or Improve, as Applicable)	95% (can opt to meet 0.15 rate in lieu of	1-Jan-05	Install SCR & Operate Year-Round	0.11	1-Jan-08				Units 1, 2 and 3 have installed FGD. Units 1 & 2 have installed SCR. These controls are built into EPA Base Case 2004. The SCR requirement for unit 3 is

Company and Plant	Unit	Settlement Actions: Retire/Repower: Action	Retire/Repower: Effective Date	SO$_2$ Control: Equipment	SO$_2$ Control: Percent Removal or Rate (lb/mmBtu)	SO$_2$ Control: Effective Date	NO$_x$ Control: Equipment	NO$_x$ Control: Rate (lb/mmBtu)	NO$_x$ Control: Effective Date	PM or Mercury Control: Equipment	PM or Mercury Control: Rate (lb/mmBtu)	PM or Mercury Control: Effective Date	Notes
					percent removal, pending demonstration)								modeled as an emissions constraint.
Chesterfield	Unit 4						Install SCR & Operate Year-Round	0.1	1-Jan-13				SCR on this unit is modeled as an individual emission constraint in EPA Base Case 2004.
	Unit 5			FGD (Construct or Improve, as Applicable)	95% (can opt to meet 0.13 rate in lieu of percent removal, pending demonstration)	12-Oct-12	Install SCR & Operate Year-Round	0.1	1-Jan-12				SCR and FGD on this unit are modeled as individual emission constraints in EPA Base Case 2004.
	Unit 6			FGD (Construct or Improve, as Applicable)	95% (can opt to meet 0.13 rate in lieu of percent removal, pending demonstration)	1-Jan-10	Install SCR & Operate Year-Round	0.1	1-Jan-11				SCR and FGD on this unit are modeled as individual emission constraints in EPA Base Case 2004.
Chesapeake Energy Center	Units 3 and 4						Install SCR & Operate Year-Round	0.1	1-Jan-13				SCR on these units are modeled as individual emission constraints in EPA Base Case 2004.
Clover	Units 1 and 2			Improve Existing FGD	95% (can opt to meet 0.13 rate in lieu of percent removal, pending demonstration)	1-Sep-03							Settlement requires system-wide interim NO$_x$ control actions, but the interim actions occur before the initial model run year so EPA didn't include them in EPA Base Case 2004. FGD on Clover units 1 & 2 are hardwired into EPA Base Case 2004.
Possum Point	Units 3 and 4	Retire and Repower to Natural Gas	2-May-03										This action is hardwired into EPA Base Case 2004
Santee Cooper													
Cross	Unit 1			Upgrade	95%	30-Jun-06	Install &	0.1	31-May-				SCR must be in operation on unit

Company and Plant	Unit	Settlement Actions											Notes
		Retire/Repower		SO_2 Control			NO_x Control			PM or Mercury Control			
		Action	Effective Date	Equipment	Percent Removal or Rate (lb/mmBtu)	Effective Date	Equipment	Rate (lb/mmBtu)	Effective Date	Equipment	Rate (lb/mmBtu)	Effective Date	
				Existing FGD & Continuously Operate			Continuously Operate SCR (or approved equiv control tech)		04				1 upon entry of the consent decree. FGD must be upgraded by Dec 31, '05. Effective dates for NO_x rate & SO_2 efficiency are as shown in table. SCR and FGD are hardwired into EPA Base Case 2004.
	Unit 2			Upgrade Existing FGD & Continuously Operate	87%	30-Jun-06	Install & Continuously Operate SCR (or approved equiv control tech)	0.11 / 0.1	May 31, 2004 / May 31, 2007				SCR must be in operation on unit 2 upon entry of the consent decree; effective date for 0.11 NO_x rate is May 31, '04 & for 0.1 NO_x rate is May 31, '07. FGD must be upgraded by Dec 31, '05; effective date for SO_2 efficiency is as shown in table; FGD upgrade must be designed to 91% removal efficiency. SCR is hardwired into EPA Base Case 2004.
Winyah	Unit 1			Install & Continuously Operate FGD (or approved equiv tech)	95%	31-Dec-08	Install & Continuously Operate SCR (or approved equiv control tech)	0.11 / 0.1	Nov 30, 2004 / Nov 30, 2007				SCR must be in operation on unit 1 by May 31, '04; effective date for 0.11 NO_x rate is Nov 30, '04 & for 0.1 rate is Nov 30, '07. FGD must be in operation by June 30, '08; effective date for SO_2 efficiency is as shown in table. SCR is hardwired into EPA Base Case 2004. SCR is modeled as individual emissions constraint.
	Unit 2			Install & Continuously Operate FGD (or approved equiv tech)	95%	31-Dec-08	Install & Continuously Operate SCR (or approved equiv control tech)	0.12	30-Nov-04				SCR must be in operation on unit 2 by May 31, '04. FGD must be in operation by June 30, '08; effective date for NO_x rate & SO_2 efficiency are as shown in table. SCR is hardwired into EPA Base Case 2004. FGD is modeled as individual emissions constraint.
	Unit 3			Upgrade Existing FGD & Continuously Operate	90%	31-Dec-12	Install & Continuously Operate SCR (or approved equiv control tech)	0.14 / 0.12	Nov 30, 2005 / Nov 30, 2008				SCR must be in operation on unit 3 by May 31, '05; effective date for 0.14 NO_x rate is Nov 30, '05 & for 0.12 rate is Nov 30, '08. FGD must be upgraded by June 30, '12; effective date for SO_2 efficiency is as shown in table. SCR is hardwired into EPA Base Case 2004. FGD is modeled as

		Settlement Actions											
		Retire/Repower		SO_2 Control			NO_x Control			PM or Mercury Control			
Company and Plant	**Unit**	**Action**	**Effective Date**	**Equipment**	**Percent Removal or Rate (lb/mmBtu)**	**Effective Date**	**Equipment**	**Rate (lb/mmBtu)**	**Effective Date**	**Equipment**	**Rate (lb/mmBtu)**	**Effective Date**	**Notes**
													individual emissions constraint.
	Unit 4			Upgrade Existing FGD & Continuously Operate	90%	31-Dec-07	Install & Continuously Operate SCR (or approved equiv control tech)	0.13 / 0.12	Nov 30, 2005 / Nov 30, 2008				SCR must be in operation on unit 4 by May 31, '05; effective date for 0.13 NO_x rate is Nov 30, '05 & for 0.12 rate is Nov 30, '08. FGD must be upgraded by June 30, '07; effective date for SO_2 efficiency is as shown in table. SCR is hardwired into EPA Base Case 2004. FGD is modeled as individual emissions constraint.
Grainger	Unit 1						Operate Low NO_x Burner (or More Stringent Technology)		Upon Entry of the Consent Decree				LNBs on units 1 & 2 are hardwired in EPA Base Case 2004.
	Unit 2						Operate Low NO_x Burner (or More Stringent Technology)		1-May-04				
Jefferies	Units 3 & 4						Operate Low NO_x Burner (or More Stringent Technology)		Upon Entry of the Consent Decree				LNBs on units 3 & 4 are hardwired in EPA Base Case 2004.

Notes

1. This summary table describes New Source Review settlement actions as they are represented in EPA Base Case 2004. The settlement actions are simplified for representation in the model. This table is not intended to be a comprehensive description of all elements of the actual settlement agreements.

2. Settlement actions for which the required emission limits will be effective by the time of the first model run year (before January 1, 2007) are built into the database of units used in EPA Base Case 2004 ("hardwired"). However, future actions are generally modeled as individual constraints on emission rates in EPA Base Case 2004, allowing the modeled economic situation to dictate whether and when a unit would opt to install controls versus retire.

3. Some control installations that are required by these NSR settlements have already been taken by the affected companies, even if deadlines specified in their settlement haven't occurred yet. Any controls that are already in place are built into EPA Base Case 2004.

4. If a settlement agreement requires installation of PM controls, then the controls are shown in this table and reflected in EPA Base Case 2004. If settlement requires optimization or upgrade of existing PM controls those actions aren't included in EPA Base Case 2004. EPA doesn't model PM emissions in EPA Base Case 2004.

5. For units for which an FGD is modeled as an emissions constraint in EPA Base Case 2004, EPA used the assumptions on removal efficiencies that are shown in Table 5-2 of this documentation report.

6. For units for which an FGD is hardwired in EPA Base Case 2004, EPA assumed installation of an FGD with a percent removal of 95% (except for PSEG Hudson unit 2 and Mercer units 1 & 2, for which the settlement specifies dry FGD and EPA assumes a percent removal of 90%).

7. For units for which an SCR is modeled as an emissions constraint or is hardwired in EPA Base Case 2004, EPA assumed an emissions rate equal to 10% of the unit's uncontrolled rate, with a floor of 0.06 lb/mmBtu or used the emission limit if provided.

8. The applicable low NO_x burner reduction efficiencies are shown in Table A3-1:3 in Appendix 3-1.

9. EPA included in EPA Base Case 2004 the requirements of the settlements as they existed on March 19, 2004. At that time the WEPCO and Santee Cooper settlements hadn't yet been entered by judge.

10. Some of the NSR settlements require the retirement of SO_2 allowances. For Base Case 2004, EPA estimated the amount of allowances to be retired from these settlements and adjusted the total Title IV allowances accordingly. See Table 6-4.